REBUTTAL TESTIMONY OF

MARGOT EVERETT

ON BEHALF OF

DOMINION ENERGY SOUTH CAROLINA, INC.

DOCKET NO. 2020-229-E

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND OCCUPATION.

A. My name is Margot Everett. My business address is 101 California Street, Suite 4100, San Francisco, California 94111. I am a Director for Guidehouse and will provide testimony on behalf of Dominion Energy South Carolina, Inc. ("DESC").

Q. ARE YOU THE SAME MARGOT EVERETT THAT OFFERED DIRECT TESTIMONY IN THIS DOCKET?

A. Yes, I am.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to address several issues raised by various parties regarding the design of the net energy metering ("NEM") tariffs submitted by DESC in this docket (the "Solar Choice Tariffs"). Among other things, I will address the cost basis of the Solar Choice Tariffs and the interplay of each component of the rate design.

COST OF SERVICE

Q. WITNESSES HORII, BEACH, AND BARNES PROVIDED TESTIMONY IN THE GENERIC DOCKET OUTLINING THE ROLE THAT EMBEDDED COST OF SERVICE STUDIES AND MARGINAL COST OF SERVICE STUDIES PLAY IN EXAMINING COST OF SERVICE IMPLICATIONS IN THE NEM CONTEXT. WHAT IS THE DIFFERENCE BETWEEN EMBEDDED AND MARGINAL COST-OF-SERVICE STUDIES AND THE TYPICAL APPLICATION OF EACH?

A. To understand that question, I think it is helpful to first address the purposes for which cost-of-service studies are employed. Cost-of-service studies are used for several purposes throughout the rate-setting process. The first, and most common, application of a cost-of-service study is to allocate revenue requirement to different customer classes from which those revenues would be collected. Next, cost-of-service studies can inform rate design decisions by designating costs by driver and then setting individual rate components based on those drivers (e.g., customer charge vs demand charge). Finally, cost-of-service studies can be used to determine whether a customer or group of customers is covering their cost-of-service through their bill payments. This last application assists in identifying 'cost shifts' resulting from rate structures where some customers are paying far less than their cost-of-service while others are paying far more. This occurs because rates and allocations are based on the total or average of the class and there are customers within each class that have usage patterns that are different from the class average.

Turning to the question, as noted by the various witnesses in this docket, there are typically two types of 'cost of service' studies employed by the utility industry: embedded cost-of-service and marginal cost-of-service. An embedded cost-of-service study is backward-looking and focus on actual costs that need to be recovered by a utility in a specific year (DESC uses the term 'historic test year'). The study then segments all these costs based on the function (e.g., generation, transmission or distribution) and category (e.g., distribution demand, customer billing etc.). These studies also identify the driver of the costs, such as demand (kW), energy (kWh) or customer (customer month). Ultimately the embedded cost of service study yields average costs by driver. Table 1 shows DESC's most recent unit costs.

The results of an embedded cost-of-service study is a set of 'allocators' by customer class for different types of costs that can be used to determine the level of revenues to collect from each customer class. These allocations are then applied to the utilities authorized revenue requirement (note that this can mean that the total costs used in the cost of service, which is based on a test year, may vary from the utilities' authorized revenue). Embedded cost studies are a useful way of understanding how a customer class has 'contributed' to the costs to serve and thus a common means for revenue allocation. The embedded cost-of-service study can also provide the level of costs associated with a function (e.g., generation, transmission etc.) included in the revenue requirement allocated to the customer class. This informs the rate design, helping distinguish which costs are best recovered from monthly charges, demand charges, energy charges or even subscription charges.

Marginal cost studies examine the incremental costs of supplying or delivering energy to a customer. Marginal cost-of-service studies are designed to create a statistical relationship between load growth and capital costs. These studies require understanding the costs a utility is planning to spend to meet future load growth (generation, transmission and distribution capacity needs) that can be avoided if the load growth is no longer expected. Specifically, the costs included in a marginal cost study should only relate load growth, not cost associated with lifecycle replacements, grid hardening, grid modernization or grid restoration and repair. Therefore, the level of costs included in a marginal cost-of-service study can be far less than total planned costs. Ultimately the marginal cost-of-service study yields marginal costs by cost driver (e.g., demand or kW and energy or kWh).

The results of a marginal cost-of-service study can also be used to develop a set of 'allocators' by customer class for different types of costs that can be used to determine the level of revenues to collect from each customer class. This is done by computing marginal cost revenues for each customer class by taking the marginal costs times the cost drivers for the class (e.g., marginal generation capacity costs times system peak load before losses). However, marginal cost revenues seldom add up to total embedded costs. Therefore, marginal costs are 'scaled' to total revenues. These scaled marginal costs are then used to allocate revenue requirement to each customer class. Marginal cost-of-service studies are useful in allocating cost but also in determining the expected incremental cost to serve individual customers, and conversely the value of 'avoiding' a kW or kWh of growth. Finally, marginal costs are useful in informing rate design. Rate design can be structure to incent 'avoiding' the costs creating price differentials that result in limited costs shifts from changes in customer behavior because as the customer's change in load corresponds to the change in the utility's cost.

Q. HOW SHOULD EMBEDDED AND MARGINAL COST-OF-SERVICE STUDIES BE APPLIED IN DEVELOPING THE SOLAR CHOICE TARIFFS?

A. It is important to remember that cost allocation is a zero-sum game. As costs allocated to one group of customers are changed, costs previously allocated to those customers are 'shifted' to other customers. In the case of customer-generators, we must be careful in determining 'cost of service' using embedded costs because it is backward looking. Before a customer installs a behind-the-meter system, the customer is contributing to the overall 'size' of their class and thus the allocation of costs to that class. Rates are designed to recover those costs, and then the customer pays based on the 'average' of those costs (total costs allocated divided by units for that costs such as kWh). Once those rates are set in a rate case, the costs to serve that customer are based on their use at the time of the study, regardless of any change in an individual customer's use. If a customer then installs a system that reduces their load, they have not changed the embedded cost allocations and their customer class remains responsible for those allocated embedded costs. Only avoided costs, or costs saved by the utility, reduce the allocated costs.

Q. HOW DO YOU RESPOND TO WITNESS BARNES' ALLEGATION ON PAGE 5, LINES 14 THROUGH 16, THAT "ONE OF THE CRITICAL DEFICIENCIES IN DOMINION'S PROPOSAL IS THAT IT LACKS SUPPORT FROM A COST OF SERVICE EVALUATION?"

A. This is simply incorrect. In the Generic Docket, as required by Act 62, DESC conducted a cost of service analysis of the current NEM program. This is the only cost of service analysis required by Act 62, which required an assessment of the customer-generators' impact on DESC's "long-run marginal costs of generation, distribution, and transmission."[1] Further, for this assessment DESC used marginal costs that were from various Commission decisions.

[1] S.C. Code Ann. § 58-40-20(D)(1).

Nevertheless, for purposes of designing rates for the Solar Choice Tariffs, DESC leveraged the embedded cost-of-service study it conducted to support its rate case in Docket No. 2020-125-E and marginal costs values from its most recent avoided cost proceeding. The results are provided in Table 5 of my direct testimony. In this study, DESC quantified the level of revenue a customer would have to pay had they been on their class's Commission-approved rate prior to installing a behind the meter system, and the results are shown in Table 5 of my direct testimony. This is appropriate because Commission approved rates are cost-based reflecting the costs allocated to that customer class via the embedded cost study and thus reflective of the cost-of-service for that customer class. As noted above, the embedded cost-of-service study was used to allocate costs to the customer class and then rates are derived from those allocated costs and subsequently approved by the Commission. Further, DESC broke these costs into five buckets using the embedded cost of service study: Customer, Energy, Production Capacity, Transmission Capacity and Distribution Capacity. Using this breakdown, DESC was able to determine the appropriate levels of customer charge using customer allocated costs as well as designating types of costs by cost driver for other rate components.

To account for the fact that customer-generators self-consume some portions of the electricity they generate, which provides a benefit to the DESC system as a result of these avoided sales, DESC credited the determined benefit to the embedded cost to more accurately determine the cost of serving these customers. To do this, DESC used Commission-approved, component-specific marginal cost values. Finally, to quantify the appropriate export credit, these same Commission-approved avoided costs were used.

Q. ON PAGE 32, LINES 5 AND 6, OF HIS DIRECT TESTIMONY, WITNESS BARNES ARGUES THAT THE "AVOIDED COST RATE DOES NOT REFLECT THE FULL LONG-TERM VALUE OF CUSTOMER-SITED GENERATION." HOW DO YOU RESPOND TO THIS STATEMENT?

A. I disagree, and Witness Barnes provides no evidence in this docket to support this statement. Alternatively, DESC has used established, Commission-approved avoided costs as the basis for valuing utility purchases. DESC's approach is consistent—particularly in the case of solar purchases—with established principles of the Public Utility Regulatory Policies Act (PURPA).[2] In keeping with PURPA's requirement that state commissions establish avoided cost rates, DESC's avoided cost rates reflect the Commission-established values for solar generation purchases.

To comply with Act 236, DESC, like many other utilities, adopted netting rates structures in part to be consistent with simplistic rate designs in place to create and facilitate the development of the solar markets for residential and small commercial customers. This overly simplistic, and now outdated, structure resulted in DESC paying retail rates for customer generation exported to the DESC system.

[2] PURPA is a United States act passed November 9, 1978 and requires electric utilities to buy power from other "producers."

This inflated value for the exported solar energy created the 'banking cost shift' which must be eliminated to the "greatest extent practicable" as discussed in my direct testimony.

Q. ON PAGE 24, LINE 22, THROUGH PAGE 25, LINE 1 THROUGH LINE 15, WITNESS BARNES CRITICIZES DESC'S UTILIZATION OF ITS COST OF SERVICE STUDY FROM ITS PENDING RATE CASE WHEN DEVELOPING THE SOLAR CHOICE TARIFFS. PLEASE EXPLAIN WHY IT WAS APPROPRIATE TO LEVERAGE THAT COST OF SERVICE STUDY TO DEVELOP THE SOLAR CHOICE TARIFFS.

A. As stated above DESC leveraged the embedded cost-of-service study from its recent rate case and marginal costs (or avoided costs) approved in its most recent avoided cost proceeding. This approach was most appropriate because it reflects DESC's most recent embedded cost of service study (test year 2019), which is used to inform all of DESC's rate designs in its current rate case. Finally, these values are subject to vetting and scrutiny of both the Commission and any external stakeholder concerned with DESC's rate setting. In short, leveraging the most recent cost of service study ensures that the Solar Choice Tariffs are based on the most up to date data, costs that has been vetted and approved, and costs that are consistent with information used for setting all of DESC's rates. Running a separate study would either be redundant or outdated for all of DESC's other rates, but it would not have been more current.

Having established that DESC used the most current values for both, there are several benefits to using both the embedded and marginal studies in the DESC Solar Choice rate design. The embedded cost of service provided information regarding the cost components and cost drivers and was thus useful in determining rate structure. Further, using the marginal costs provides the best insight regarding cost-shift because it provides information regarding the true 'savings' a customer generator provides DESC. These savings were factored directly into the various rate making tools to determine actual values for each.

Q. PLEASE SUMMARIZE WHAT THE RESULTS OF THE DESC COST OF SERVICE STUDY REFLECT.

A. The results reflect that, once a customer installs a customer-generation system, their cost of service is reduced by the value of the generation they simultaneously consume behind the meter. Further, the value of the export energy does not decrease the customer's cost of service, but rather provides an additional value to the customer based on the export value provided to that customer. However, if the value of that export credit is greater than the value DESC's gains—as represented by the avoided costs—the costs of receiving and absorbing those exports can add to the overall costs to serve a NEM customer specifically. DESC's avoided cost values.

This study also revealed that size of the customer's system drives the cost of service for a customer generator. Specifically, as system size increases, the behind the meter consumption also increases, increasing the benefits to DESC and thus decreasing cost of service. However, it also increases the customer's use of DESC's system for exports. These increases are also not linear. For example, customers who install a system that is roughly the size of their 'average hourly demand', a customer would export only about 18% of their generation while a customer that sizes their system to meet the customer's total annual customer use would export over 50% of their generation. In summary, this study spotlights the linkage between cost of service for a customer generator and the size of the customer generator's system.

BEST PRACTICES

Q. DO YOU AGREE WITH WITNESS BARNES'S STATEMENT ON PAGE 7, LINE 13, THAT YOUR DESCRIPTION OF NEM BEST-PRACTICES IN THE GENERIC DOCKET IS ACTUALLY "MISLEADING?"

A. No. First, as clearly established in the Generic Docket current best practices are to adopt more accurate rate designs to accommodate the changing landscape of our industry due to advancements in technologies. These accurate rate designs include TOU rates, as envisioned by Act 62, but do not stop with TOU based rates, and include demand charges, grid access fees, minimum bills, etc. In fact, Witness Horii states in his testimony that DESC utilized "hallmarks of an ideal Solar Choice Metering Tariff"[3] by utilizing a flat monthly service charge, TOU rates, and a monthly demand charge.

To further demonstrate the changing landscape I have included Figure 1 which contains a table from North Carolina Clean Energy Technology Center, *The 50 States of Solar: 2020 Policy Review and Q4 2020 Quarterly Report*, January 2021.[4] This report summarizes the range of policy activity in the distributed generation policy arena. Despite constraints caused by COVID-19, 46 states have been considering policy actions that range from DG compensation policies, fixed and minimum bill charges and DG valuation. With over 250 actions in 2020 alone it is clear this issues related to DG is extremely dynamic, with DG compensation being the top topic being reviewed.

[Figure 1 follows]

[3] Direct Testimony of Brian Horii page 5, line 16.
[4] The NC Clean Energy Technology Center is a UNC System-chartered Public Service Center administered by the College of Engineering at North Carolina State University. Its mission is to advance a sustainable energy economy by educating, demonstrating and providing support for clean energy technologies, practices, and policies.

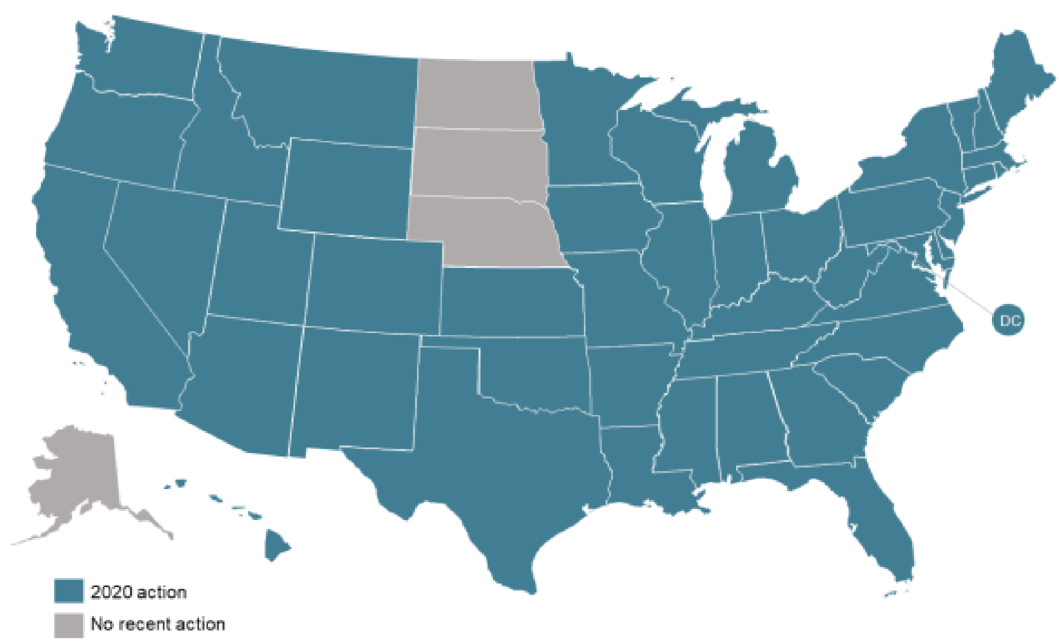
Figure 1: 2020 Summary of Policy Actions

Table 1. 2020 Summary of Policy Actions

Policy Type	# of Actions	% by Type	# of States
DG Compensation Policies	92	36%	34 +DC
Community solar	55	21%	22 + DC
Residential fixed charge or minimum bill increase	48	19%	26 + DC
DG valuation or net metering study	29	11%	17 + DC
Third-party ownership of solar	20	8%	9
Residential demand or solar charge	10	4%	7
Utility-led rooftop PV programs	3	1%	3
Total	**257**	**100%**	**46 States + DC**

Note: The "# of States/ Districts" total is not the sum of the rows, as some states have multiple actions. Percentages are rounded and may not add up to 100%.

Figure 1. 2020 Action on Net Metering, Rate Design, & Solar Ownership Policies



The above report reflects there is no one preferred combination of rate tools, but there is a common move to address cost shifts (including, to the greatest extent practicable as required by Act 62) by adopting more modern structures to replace NEM designs. While the Commission ordered a study of best practices across jurisdictions, it did so only to gather information to inform the Commission's assessments in the Solar Choice dockets. It did not require this survey to establish a "best combination."

Witness Barnes misses the fundamental point—no one set of rate design tools is required, but the Commission is required to establish a Solar Choice Tariff that:

> (1) eliminate[s] any cost shift to the greatest extent practicable on customers who do not have customer-sited generation while also ensuring access to customer-generator options for customers who choose to enroll in customer-generator programs; and
>
> (2) permit solar choice customer-generators to use customer-generated energy behind the meter without penalty.
>
> S.C. Code Ann. § 58-40-20(G).

Thus, attacking the rate design tools as not representing best practices, even if true, would be immaterial because that is not a requirement. But, employing them as DESC did to eliminate cost shift to "the greatest extent practicable" satisfies an Act 62 requirement.

SOLAR CHOICE RATE DESIGN

Q. WITNESS BARNES ON PAGE 49, LINES 20-21 STATES THE BFC "SHOULD BE BASED ON THE RATES CHARGED TO SIMILARLY SITUATED NON-PARTICIPATING CUSTOMERS." IF YOU WERE TO SET THE BFC TO THOSE RATE LEVELS, HOW WOULD THE SOLAR CHOICE RATE DESIGN CHANGE AND HOW WOULD THIS CHANGE IMPACT THE COST SHIFT?

A. The Solar Choice Rate design would not change, only the values of each rate component (e.g., BFC) would change. Specifically, any costs not collected via the BFC, which DESC has estimated to be related to customer costs, would be collected in other rate components. Assuming Witness Barnes is correct, which I disagree with, and the BFC incorrectly includes distribution costs, the result would be that these costs would allocated instead to the subscription rate. Therefore, the subscription rate would increase and the BFC would decline—the charges would not just disappear. While the effect of Witness Barnes's argument would be to move a charge from one rate tool to another in this specific example, I do not mean to suggest that one can take a casual approach to allocating costs according the corresponding causation.

It is very important to note that a basic tenet of rate design is to charge customers based on cost causation. Therefore, reallocating costs and increasing other rate components to recover those costs must be done with great care, particularly with a tariff designed to collect costs where customers have the ability to avoid paying fees related to energy, or kWh, as is particularly true with simplistic volumetric charges. If costs that are generally driven by customer service requirements, like the BFC, or related to use of the system, such as distribution and transmission costs, are relocated to a volumetric rate component (e.g., per kWh), customer generators will have an opportunity to avoid paying those costs, increasing the "Rate Design" cost shift.

Turning back to the example above where Witness Barnes' suggestion would result in a higher subscription fee, such a change would result in costs increasing with the customer's grid use. This means that customer who use the grid more pay more towards costs that are actually incurred based on the number of customers. However, I carefully studied DESC's cost of service results and, based on this analysis, I concluded the proper charge for the grid use and therefore an increase as suggested by Witness Barnes would not allow for proper cost recovery, send incorrect pricing signals, or exacerbate cost shifting.

Q. ON PAGE 29, LINE 18, WITNESS BARNES ATTACKS THE NETTING MECHANISM UNDER THE SOLAR CHOICE TARIFFS, AND INSTEAD RECOMMENDS THAT THE COMMISSION UTILIZE ANNUAL NETTING WITH EXPORTS VALUED AT THE RETAIL TOU RATES. PLEASE DESCRIBE WHY SUCH APPROACH WOULD NOT "FAIRLY ALLOCATE COSTS AND BENEFITS" IN ACCORDANCE WITH ACT 62.

A. First, recalling that netting really implies that all generation not consumed instantaneously behind the meter is 'banked' by DESC and counted against energy consumed later. Annual banking infers that a kWh generated in January at 2pm is worth a kWh consumed in July at 6pm. Witness Barnes implies that netting by TOU rate 'fixes' the fact that there are value differences between January at 2pm and July at 6pm. Witness Barnes neglects to mention that this banking scheme also assumes that the value of an export is equal to the retail rate—which is certainly not the case given that the retail rate is in excess of the costs avoided by the utility by such generation. Therefore, even though TOU banking may result in better matching time periods and seasons, it still does not fix the banking cost shift that results from the retail rate being far in excess of the avoided costs experienced by DESC. As a result, this approach would continue to create a 'Rate Design' cost shift from customer generators to other customers in their class, and not reduce the cost shift 'to the greatest extent practicable,' both in violation of Act 62.

Q. HOW DO YOU RESPOND TO WITNESS BARNES' ARGUMENT ON PAGE 4, LINES 17 THROUGH 20, THAT A MONTHLY MINIMUM BILL SHOULD BE UTILIZED IN CONJUNCTION WITH A BFC?

A. Although the Solar Choice Tariffs include a BFC and a minimum subscription, Witness Barnes and Witness Beach both propose a minimum bill structure which may sound similar to the structure of the Solar Choice Tariffs, but it yields a different result. As I stated above, you cannot simply treat the Solar Choice Tariffs—or any modern rate-making tariff—like a buffet by only picking and choosing certain aspects. For example, DESC proposes a BFC to address the costs DESC incurs to cover costs for items such as meter and billing that are driven by the fact that the customer takes service from DESC, regardless of usage. When I examined DESC's cost of service study, I determined these basic costs are not being fully recovered and are being shifted to non-participating customers. This cost shift primarily arises because the amount of the BFC is insufficient to actually recover the average customer cost per customer. The difference in costs between the BFC and the average customer are being shifted to the volumetric rate to non-participating customers. Again, cost allocation is a zero sum game and as one rate component is exogenously or arbitrarily 'set' (e.g., BFC), the costs not collected are, necessarily, collected via another rate component (e.g., kWh).

These costs are outlined in Table 5, line 1, of my Direct Testimony in the Generic Docket, and substantiate this explanation. By adopting a cost-reflective BFC, DESC will be able to address the under collection of "customer costs."

On the other hand, the use of minimum bills in the context of NEM rate design is to ensure some collection of costs at times when customers netting results in a customer's bill approaching a *de minimis* value, or approaching zero. To illustrate why these rate tools cannot be selectively applied, assume a customer consumed electricity that results in a $100 monthly electric bill. Also, assume the

BFC is $10. As you can see, with a BFC, the customer's bill would be $110 per month. Now that same customer installs a customer generator and, with the help of netting, the customer's consumption results in an electric bill of $5. With the same rate structure as above that yielded a bill of $110, the customer would now pay $15 for that month. However, if you apply a minimum bill of $10 and eliminate the BFC, as proposed by Witnesses Beach and Barnes[5], the customer's bill would only be $10. This not only illustrates the interdependence of rate tools and selecting the right combination, it also highlights that Witness Barnes and Witness Beach are not interested in eliminating cost-shift. In fact, it shows the opposite—that their intent is to benefit Solar Choice by proposing an new Solar Choice rate that further shifts costs to non-participants regardless of income level.

Q. HOW DO YOU RESPOND TO WITNESS BARNES' ALLEGATION ON PAGE 49, LINES 3 THROUGH 4, THAT DESC'S CALCULATION OF THE BFC "AMOUNTS TO DISCRIMINATION, PENALIZING CUSTOMERS SOLELY BASED ON THE PRESENCE OF CUSTOMER-SITED GENERATION?"

A. As a fundamental matter, charges that reflect the cost of service are not penalties. The BFC is designed to collect those costs that apply to serving a customer regardless of whether that customer consumes 1 kWh or 10,000 kWhs.

[5] Note both Witness Beach and Barnes set their minimum bill to the BFC value they contend is appropriate.

Costs relating energy delivery as well as costs relating to line drops, meters and billing are all costs associated with serving customers regardless of consumption. Also, DESC's current residential and small commercial customer rates have BFC, thus it is not discriminatory to include a similar charge in the Solar Choice Tariffs.

As I discussed above, I analyzed DESC's cost of service study to determine whether costs associated with serving customers were properly recovered and I concluded that the costs allocated to customer were most appropriately recovered through a monthly fixed charge, such as the BFC and consistent with best practices in designing cost reflective rates. Because I determined Solar Choice customers would not otherwise pay their fair share of these customer related costs if these costs were to be collected via a volumetric (per kWh) charge, a BFC was employed because it addresses the current under-collection of these costs. As such, DESC followed Act 62's directive to allocate according to cost-causation principles, rather than simply imposing arbitrary penalties for consuming generation behind the meter.

Q. HOW DO YOU RESPOND TO WITNESS BARNES' ALLEGATION ON PAGE 52, LINES 14 THROUGH 20, THAT DESC'S SUBSCRIPTION CHARGE IS INCONSISTENT WITH "COST CAUSATION PRINCIPLES?"

A. His allegation is false. I note that Witness Beach makes a similar argument, but they are easily dispensed by taking a closer look at the intent and functionality of the subscription rate, which supports the fact that the subscription is consistent with cost causation principles. Rates are frequently designed to create a simplistic relationship between something that can be measured on a customer basis—such as kWh of energy or system size—and then the costs allocated to the customer class are distributed based on that measure. The challenge with a per kWh charge for NEM is that customers are consuming much less energy without a corresponding change in costs, which is inconsistent with cost-causation principles because it permits a customer to avoid paying costs by using less, even though that cost to serve does not.

Instead, the subscription charge is calculated based on the size of the system rather than such customer's kWh consumption which can dramatically decline upon installation of these systems. Calculating the subscription fee based upon system size rather than kWh consumption is appropriate because transmission and distribution costs are driven by the customer's demands on the DESC system. Upon installation of the customer's on-site generation, the customer's demands on the DESC system do not dramatically change—and possibly increase—because they are now both pulling energy from the system when the generator is not meeting customer's demand and putting energy onto the system when the generator is producing more energy that the customer is using.

This two-way flow is directly correlated with the size of the customer's system, which dictates the amount of energy generated and thus, to a point, the amount the customer can reduce the energy delivered by DESC. However, as noted above, reduction in energy delivered does not reduce the demands on the system given the two-way flow. Understanding this relationship between system size and use of the system, be it delivery or receipt of energy, creates clarity as to the appropriateness of a subscription charge that is related to the size of the system. Using energy-based, volumetric rates to recover transmission and distribution costs is not consistent with cost-causation principles for customers with behind-the-meter generation—particularly uncontrolled intermittent generation. The Solar Choice Tariffs take that extra step toward developing a cost-reflective rate that ensures the reduction in the "Rate Design" cost-shift is reduced to the "to the greatest extent practicable" in accordance with Act 62.

Q. DO YOU AGREE WITH WITNESS BARNES' STATEMENT ON PAGE 53, LINE 11, THAT THE ARIZONA PUBLIC SERVICE SAVER CHOICE TARIFF INCLUDES A SUBSCRIPTION CHARGE "BUT NOT IN THE A MANNER THAT IS SIMILAR TO WHAT THE COMPANY PROPOSES?"

A. No. Witness Barnes is basically arguing that DESC's proposal is unreasonable simply because its subscription fees are higher than those utilized by APS. While it is true APS has lower subscription and BFC charges compared to DESC, the TOU rates utilized by the APS are significantly higher (upwards of 8 to 10 cents a kWh). This highlights the danger of simply examining certain rate components in a vacuum outside of the broader context within which they are employed. Essentially, the critical question is how rate tools and values interplay with each other to accomplish the overall goals of a tariff. To illustrate this point, DESC applied the APS rate to the customer profiles and Table 1[6] below compares APS' Residential Time of Use Saver Choice rate components with DESC's Solar Choice Tariffs. This APS rate is the standard offering with no demand charges and thus most 'comparable' to the Solar Choice Tariff option.

First, Table 1, Row 19 shows the expected bills before installing solar for both APS and DESC. The differences in total bills immediately demonstrates the point that comparing cost levels across jurisdictions can be misleading as APS's 'Saver Choice' rate results in a bill 20% higher than DESC's current residential rate—information conveniently omitted by Witness Barnes.

Next, Table 2 shows both APS's (first column) and DESC's (second column) charges by rate component:

- Fixed charge (see Row 21);
- Time varying rates (see Rows 24-27) with APS having the addition of a super off-peak rate reflective of APS's system costs;
- Subscriptions or Grid Charge (Row 10); and

[6] https://www.aps.com/-/media/APS/APSCOM-PDFs/Utility/Regulatory-and-Legal/Regulatory-Plan-Details-Tariffs/Residential/Service-Plans/SaverChoice.ashx?la=en

- Export credits (Rows 33-36), noting APS does not have a time differentiated export rate.

Finally, Table 1, Row 39 shows that the bills savings, on a percentage basis, after installation of a system roughly equal to the customer average demand (consistent with the 3kW proposed as benchmark for DESC's rate). This shows that the savings is basically the same the two rates.

This close comparison at small system size reflects the rate design differences most appropriately, and shows the APS rate, under the policies dictated in Arizona, yields similar cost savings. However, it is clear that the economics of the APS tariff, all other things being equal, favor the installation of larger systems in a way that the Solar Choice Tariffs do not. Specifically, because, as Witness Barnes notes, the "Grid Access Charge" is lower than the Solar Choice Tariff, and the export credit is greater, naturally as a customer installs larger systems, and exports more of that generation the value increases. Let's take a simple example where the customer installs a 7.2kW system and has the same load profile. This customer would generate an additional 6,897 kWh/year and thus export an additional 5,251 kWh/year and receiving an additional $494 a year in export credits. This customer would then pay an additional $46.87/year in grid access charges therefore gaining $447/year from just oversizing their system relative to their average hourly usage. Only if this additional $447/year of payments equates to the utility's saved costs, which cannot be determined by studying the rate design and is uniquely dependent upon APS's specific cost of service, are non-participating customers unharmed. As DESC has noted, under the current Act 236 NEM program, customers are gaining substantial benefits from exports to offset costs and contributing to the cost shift. To address the current cost shift, DESC's Solar Choice rate structure is intentionally designed to create an incentive for customers to install systems that maximize behind the meter self-consumption versus total system generation.

Lastly, the comparison of DESC's rate with the APS rate highlighted by Witness Barnes further emphasized the fact that all aspects of the rate need to be reviewed in concert and adjusting the component of one rate can lead to different bills savings and, more importantly, reductions on the cost shift. It further demonstrates how rate values can differ from one utility or jurisdiction to another as they are dependent upon the specific, and many times unique, characteristics of the utility's system and cost of service.

[Table 1 follows]

Table 1: DESC vs APS Rate Comparison

Row		APS Saver Choice	DESC Proposed	Annual Use APS TOU	Annual Use DESC TOU
1	**BEFORE INSTALLATION**				
2	**Monthly Basic Facilities Charge**	$12.99			
3	Annual BFC	$155.86			
4	**Time of Use Rates**				
5	Summer Peak	$0.2431		2312	
6	Winter Peak	$0.2207		1320	
7	Off-Peak	$0.1087		8733	
8	Super Off-Peak	$0.0320		1179	
9	Annual Energy Charges	$1,841		13544	
10	**Grid Access Charge**	$0.93			
11	Annual Grid Charge	$0.00			
12	Other Bill Adjustments*	$0.00			
13	**Export Credits**				
14	Summer Peak	$0.09405		-	
15	Winter Peak	$0.09405		-	
16	Off-Peak	$0.09405		-	
17	Super Off-Peak	$0.09405		-	
18	Credits	$0.00000		-	
19	**Total Bill Before PV**	$1,997	$1,660		
20	**AFTER INSTALLATION**				
21	**Monthly Basic Facilities Charge**	$12.99	$19.50		
22	Annual BFC	$155.86	$234.00		
23	**Time of Use Rates**				
24	Summer Peak	$0.2431	$0.1675	1714	882
25	Winter Peak	$0.2207	$0.1842	1043	489
26	Off-Peak	$0.1087	$0.0674	6531	8144
27	Super Off-Peak	$0.0320	$0.0000	226	0
28	Annual Energy Charges	$1,364	$786	9514	9514
29	**Grid Access Charge**	$0.93	$5.40		
30	Annual Grid Charge	$33.48	$194.40		
31	Other Bill Adjustments*	$0.00	$0.00		
32	**Export Credits**				
33	Summer Peak	$0.09405	$0.00365	12	12
34	Winter Peak	$0.09405	$0.00380	50	50
35	Off-Peak	$0.09405	$0.00362	332	332
36	Super Off-Peak	$0.09405	$0.00000	503	503
37	Credits	$84	$1	897	897
38	**Total Bill with PV**	$1,469	$1,213		
39	**Percent Bill Savings**	26%	27%		

* Includes T&D costs in 'Subscription' for DESC less net generation credit of $145/year

Q. DO YOU AGREE WITH WITNESS BEACH'S STATEMENT ON PAGE 12, LINE 9 THROUGH 12, THAT RATE 5 TOU PROVIDES A "MORE ACCURATE AND COST-BASED RATE" THAN THE RATE 9 TOU RATES PROPOSED IN THE SOLAR CHOICE TARIFFS?

A. No. As noted above, the Solar Choice Tariffs are based on updated 2019 data and apply best practices to develop time-differentiated rates for both energy and non-energy cost components (e.g., energy vs capacity). Therefore, these rates are the most up-to-date as they reflect the latest information on grid costs. Rate 5 is a rate design that has been essentially unchanged since 1987. While it still serves a valid purpose, Act 62 specifically contemplates a more accurate rate structure that allocates costs and benefits and aligns rates with the cost to serve these customer-generators. This necessarily required an examination of more recent data to ensure that the Solar Choice Tariffs fulfill those goals.

IMPLEMENTATION OF TOU RATES

Q. ON PAGE 37, LINE 23, WITNESS BARNES ARGUES THAT CUSTOMERS SHOULD HAVE "ACCESS TO AT LEAST 12 MONTHS OF INTERVAL USAGE DATA" PRIOR TO BEING PLACED ON A TOU RATE. DOES THIS REFLECT AN NEM BEST PRACTICE?

A. No, nor does it reflect best practices for implementing optional TOU rates in general, particularly since many states are just starting to roll-out interval meters to track such data for all customers. Witness Barnes' request is even more curious when examined in the context of the Current NEM Programs. Remember, existing NEM customers have the option to remain on their current NEM tariff until 2025 or 2029, depending upon their enrollment date.

Second, only customers who <u>choose</u> to install customer-generation after the implementation of this rate, and then apply for the Solar Choice Tariffs, would be subject to this TOU rate. DESC is not requiring the customer to install a customer generator system. Rather, the decision is within the customer's control and the customer will not be forced onto any Solar Choice Tariff against their will.

Q. ON PAGE 10, LINES 4 THROUGH 6, OF HIS DIRECT TESTIMONY, WITNESS BEACH NOTES THAT CUSTOMERS ARE SIMPLY UNABLE TO UNDERSTAND AND EVALUATE THEIR INVESTMENT IN ROOFTOP SOLAR WITHOUT "GRANULAR DATA ON THEIR TIME-VARYING ENERGY USE OVER THE COURSE OF THE YEAR." IN YOUR EXPERIENCE, ARE CUSTOMERS ABLE TO ADAPT AND RESPOND TO TOU RATES WITHOUT THIS DATA?

A. Yes, they are. This is similar to Witness Barnes' request for more time above, which is striking given that I am unaware of any jurisdiction that requires customers have a year's worth of usage data <u>prior to even implementing an optional TOU rate</u>. Regardless, Witness Beach fundamentally misses the point. In my experience, helping a customer better adapt to a TOU rate is not about providing historical data, but it is more about providing them with information about potential behavioral changes in the future to manage their energy use consistent with TOU rate designs.

ENERGY EFFICIENCY PROGRAMS AND NEM

Q. DO YOU AGREE WITH WITNESS ZIMMERMAN'S STATEMENT ON PAGE 6, LINES 20-23, OF HIS DIRECT TESTIMONY THAT FROM A UTILITY PERSPECTIVE, NEM IS NO DIFFERENT THAN "ENERGY EFFICIENCY IMPROVEMENTS, LOAD REDUCTIONS, OR DEMAND-SIDE-MANAGEMENT?"

A. Only in part. A customer installing equipment behind the meter to reduce their bill creates the same 'bill savings' whether the customer installs an energy efficient air conditioner or a customer generator. In this example they are the same. However, where they differ is in two other aspects of customer generation. First, customer generation does not have the same impact or predictability of demands on a utility's grid. An energy efficient air conditioner will always use less energy than the replaced air conditioner while the energy from a customer generator is less reliably predictable. Further, energy efficiency programs generally provide discrete credits or payments to offset the cost of the equipment installation based on the benefits of the program. For customer generator systems to be economic, the customer must be able to monetize the values of all the energy generated and thus export to the grid. These exports are an added incentive and persist for the life of the system and, if tied to retail rates, increase with rate increases. Therefore, customer generation systems are distinctly different and require more sophisticated rate designs like that proposed by DESC.

Witness Beach suggests that DESC's Solar Choice Tariffs are inconsistent with this requirement of Act 62, using the total energy generated by a solar PV system, with an example from energy efficiency technologies. This example displays a fundamental misunderstanding of the differences between energy generation and energy reduction. A solar PV system is not always generating energy. Unlike a more efficient appliance, the at any given moment, a solar PV system may not be generating energy. If the system is not generating energy, it is not reducing a customer's load. Allowing the customer to use their own energy behind the meter without penalty means compensating them at retail rates when the customer is actively using their solar power, and their load is reduced. This does not mean that they should be guaranteed a payment stream for extra energy they generate that is exported, and thus by definition is not consumed behind the meter.

NETTING OPTIONS

Q. ON PAGE 9, LINE 14, WITNESS ZIMMERMAN'S PROPOSES THAT THE COMMISSION ADOPT A YEARLY NETTING PERIOD. HOW WOULD

THIS AFFECT NON-NEM CUSTOMERS COMPARED TO THE NET BILLING UNDER THE SOLAR CHOICE TARIFFS?

A. Longer netting periods allow more 'banking' and would run contrary to the fundamental NEM-related tenet of Act 62—reducing cost shift "to the greatest extent practicable." A net billing concept that values exports at avoided costs is a far more cost-reflective approach to accommodating the uncontrolled intermittent excess generation from customer-generators than Witness Zimmerman's preferred annual netting periods where exports are arbitrarily valued at retail rates. Put simply, the longer the netting period, the further removed from the cost-causation language in Act 62. Witness Zimmerman's recommendation reflects complete indifference to the language of Act 62.

Q. PLEASE RESPOND TO WITNESS ZIMMERMAN'S STATEMENT ON PAGE 10, LINE 21, THAT "THERE IS NO SUPPORT FOR HOURLY-NETTING IN [ACT 62]."

A. He may be correct the words "hourly netting" do not actually appear in Act 62 but the justification for hourly netting runs throughout Act 62. As Witness Kassis notes, Witness Zimmerman never once references the General Assembly's express requirement to eliminate cost shift to the greatest extent practicable. Because of his refusal to acknowledge that <u>requirement, perhaps he fails to see the justification.</u>

Hourly netting, or banking, is the most direct and reasonable means for eliminating the banking cost shift; hence, the justification in Act 62. The best support for hourly netting is that any export is requiring the utility to effectively purchase that kWh from the customer. The purchase price of that kWh under any banking mechanism is the retail rate in that the customer's consumption of a kWh is offset by the banked kWh. Any time DESC is required to pay more for a kWh of energy to deliver to their customers that the wholesale market or avoided cost results in overpayment and thus higher rates for non-participating customers.

Q. ON PAGE 13, LINES 2 THROUGH 4, WITNESS ZIMMERMAN STATES THAT "ANYTHING LESS THAN FULL RETAIL CREDIT FOR CONSUMPTION OF CUSTOMER-GENERATION . . . IS DISCRIMINATORY." ARE YOU AWARE OF ANY JURISDICTION THAT WOULD SUPPORT THIS STATEMENT?

A. No, certainly not. The idea of requiring a 'full retail credit' for self-consumption is in direct contradiction to the best practice of designing cost-reflective rates. Witness Zimmerman wants a customer to be able to avoid paying their fair share of the costs to serve a customer-generator by stating that simply reducing energy consumption reduces their cost of service in-kind with the retail rate. Throughout both my direct and rebuttal testimony I have described how the cost to serve a customer -generator is only modestly reduced by self-consumption, and that reduction has been fully incorporated in the Solar Choice Tariff design. Further, I've also demonstrated that customer generators use the system to export power and thus the size of their system relative to their average hourly use influences the customer-generator's cost to serve in ways a non-participant's cost of service cannot.

Q. ON PAGE 4, LINES 4 THROUGH 6, WITNESS BEACH STATES THAT "ALL EXCESS ON-PEAK KWH THAT ARE ROLLED OVER TO SUBSEQUENT MONTHS" SHOULD ONLY BE USED AS CREDITS AGAINST SUBSEQUENT ON-PEAK CONSUMPTION. IN YOUR EXPERIENCE, IS THIS CONSIDERED AN NEM BEST PRACTICE?

A. This banking scheme has been used but not considered a "best practice" as it still assumes that the value of the export is equal to the retail rate, be it a flat rate, tiered rate or TOU rate. More importantly, it certainly could not be seen as a best practice with respect the mandates of Act 62. As I noted above, the 'banking cost shift' results from allowing banking of a kWh exported to the grid to be used to offset a kWh of electricity delivered by DESC to that customer in a different hour. As stated above, the commission has already agreed that the value of a kWh export is not equal to the retail rate as designated by application of the NEM methodology in cost recovery mechanisms for the current NEM program and the establishment of purchase power rates from customer generation under PURPA. Lastly, as noted in my direct testimony, jurisdictions are looking closely at the banking concepts of exports and the impact on cost shift and moving toward 'net billing' structures. Continuing to provide a one for one credit for kWh export to offset a kWh used, regardless if that credit is balanced based on TOU period, is an outdated concept and being highly scrutinized by several states.

IMPACT OF RATE PROPOSAL ON COST SHIFT

Q. DOES WITNESS BEACH'S PROPOSED TARIFF REDUCE THE COST SHIFT TO THE GREATEST EXTENT PRACTICABLE IN ACCORDANCE TO THE PLAIN LANGUAGE OF ACT 62?

No. DESC reviewed the impact on both the "Banking" and "Rate Design' cost shifts. As I outline in my direct testimony, "Banking" cost shift results from NEM programs offering "banking" of kWh, or netting that allows customers to use kWhs they generated and exported to DESC to offset kWh they consume any time during the 'netting' period. The cost shift occurs because DESC is effectively purchasing this export at the retail rate, which significantly differs from the costs DESC is able to avoid by receiving the initial exported kWh. To avoid "Banking" cost shift, customer-generators should be compensated for the value of those exports, as best represented by the costs DESC's directly avoids from these exports.

Further, "Rate Design" cost shift results from rates structures that collect fixed, demand or customer related costs via a volumetric rate. Specifically, customer-generators are able to avoid paying the cost to serve them if those costs are collected through volumetric charge that the customer is able to simply avoid by consuming electricity from their generator. To avoid "Rate Design" cost shift, a more accurate rate structure that ensures the full recovery of the costs to serve a customer-generator and these costs are not shifted to non-participating customers. First, Witness Beach's proposal makes no progress towards reducing the "Banking" cost shift because he proposes no change to the netting scheme. Witness Beach justifies this by stating that the value of these exports, or the avoided costs he estimates, is roughly 15% greater than forecasted retail rates over the next 25 years. Put simply, he believes DESC is projected to charge, on average, far less than its costs over the next 25 years. This is a position that basic logic cannot support and stands in stark contrast to Witness Horii who notes in his direct on page 6, line 19-20, "the full retail rate is far larger than the avoided cost value provided by those exports."

Second, with respect to "Rate Design" cost shift, Witness Beach's proposal only makes slight modifications to rate design by proposing the adoption of a TOU rate, pairing the Basic Facilities Charge with a minimum bill, and arbitrarily setting the minimum bill to $13.50. The TOU rate proposed by Witness Beach is the already-available Rate 5 TOU rate structure, which is a 30-year-old that has undergone minimal modifications since its establishment. The minimum bill as proposed under the Joint Tariff, as discussed above, has the potential to increase the cost-shift in all situations except where there are large netting periods and exports are over-valued.

In summary, Witness Barnes' proposed Joint Solar Choice rate design only reduces the Rate Design cost shift by about 1% and in no way reduces or even addresses the Banking Cost . In fact, his proposal only results in an immaterial change from the Current NEM Programs with the simple change toward TOU pricing, as already suggested by Act 62, and thus his proposed rate structure continues to incent customers to build systems so large that the produce the amount of electricity the customer uses but relies on DESC to take over 50% of the power and 'bank' it for them for over a year.

Q. WHAT IMPACT WOULD THE INCREASED COST-SHIFT UNDER WITNESS BEACH'S TARIFF HAVE ON LOW-INCOME CUSTOMERS?

A. It could be detrimental because low-income customers have more limited ability to access customer-generation options, in part because they either don't have the credit or resources to participate or don't own their home. Also, low-income customers are more sensitive to any amount of cost-shift than other customers. Added cost-shift resulting from customer-generation paradigms designed to stimulate the installer industry rather than reflect actual costs and benefits can be very painful for low-income customers who are already struggling to make ends meet but then are required to pay more for electricity.

Q. DOES WITNESS BARNES' PROPOSED TARIFF ON PAGE 4, LINE 17, THROUGH PAGE 5, LINE 8, REDUCE THE COST SHIFT TO THE GREATEST EXTENT PRACTICABLE IN ACCORDANCE WITH THE STATED REQUIREMENTS OF ACT 62?

No. Witness Barnes, like Witness Beach, proposes only minimal changes to the Current NEM rate structure by adopting Rate 5 TOU rates and substituting the BFC with a 'minimum bill' set to BFC levels, but retaining the current annual netting scheme. As a result, like Witness Beach's proposal, Witness Barnes' proposal embraces the continuation of the "Banking" cost shift and only marginally addresses the "Rate Design" cost shift with the TOU rate, but potentially exacerbates it with the adoption of a minimum bill equal to the level of the BFC.

Q. IN FIGURE ES-1, ON PAGE 5, OF HIS DIRECT TESTIMONY, WITNESS BEACH QUANTIFIES "SOCIETAL BENEFITS" IN EXCESS OF DESC'S AVOIDED COSTS UNDER HIS PROPOSED TARIFF. ARE YOU AWARE OF ANY JURISDICTION THAT HAS QUANTIFIED SOCIETAL BENEFITS IN EXCESS OF AVOIDED COSTS UNDER NEM PROGRAMS?

A. No, and as demonstrated in the Generic Docket, no one was able to provide an example where societal benefits are included <u>at all</u> in NEM avoided costs. Rather the best case was using these hypothetical benefits in a qualitative manner to judge the appropriateness of implementing a program or rate, not quantitatively applying these benefits, if any, to the rate or compensation levels. Avoided energy and capacity cost estimates, unlike 'societal' impacts, are directly tied to what actual costs are for the utility and based on the demonstration that those costs can and are avoided by a program. Societal benefits, however, are estimates of potential benefits based on theoretical measures of things such as job creations and other broader economic and environmental benefits. The hypothetical nature of these benefits is part of the reason why it is particularly troublesome that Witness Beach leans on societal benefits to justify the cost-shift occurring under his proposed tariff. As discussed by multiple parties in the Generic Docket, these benefits are simply too difficult to quantify to have any real effect on rates, and certainly should not be used to justify an increased cost-shift in order to prop up the solar industry in South Carolina in direct contradiction to the express words of Act 62. Indeed, any tariff proposal, including that of Witness Beach, that does not eliminate the "Banking" cost shift and significantly decrease the 'Rate Design' cost shift will create higher rates for any customer who does not have access to customer generation systems. Finally, including societal benefits requires the Commission to approve these cost levels but also deem it is appropriate to collect these costs from ratepayers—even if the these hypothetical costs do not improve the costs of utility yet alone South Carolina. In other words, actual credits will be <u>paid to</u> customer generators and <u>paid for</u> by non-participants because there will not be a corresponding decrease in utility costs. While I dispute many aspects of the Joint Tariff proposal because of its failure to eliminate cost-shift to the greatest extent practicable, their desire to monetize "societal benefits" is the most glaring example of a desire to ignore Act 62 and set rates to only encourage adoption rather than reflect actual costs and benefits.

Q. DOES THIS CONCLUDE YOUR PRE-FILED REBUTTAL TESTIMONY?

A. Yes, it does.